Investor Presentation

December 2022

TSX BTE

Advisory

In this presentation, we refer to certain specified financial and capital management measures which do not have any standardized meaning prescribed by International Financial Reporting Standards ("IFRS"). While these measures are commonly used in the oil and natural gas industry, our determination of these measures may not be comparable with calculations of similar measures presented by other reporting issuers. This presentation also contains oil and gas disclosures, various industry terms, and forward-looking statements, including various assumptions on which such forward-looking statements are based and related risk factors. Please see the Company's disclosures located at the end of this presentation for further details regarding these matters.

All slides in this presentation should be read in conjunction with "Forward Looking Statements Advisory", "Specified Financial Measures Advisory", "Capital Management Measures Advisory" and "Advisory Regarding Oil and Gas Information".

This presentation should be read in conjunction with the Company's consolidated interim unaudited financial statements and Management's Discussion and Analysis ("MD&A") for the period ended September 30, 2022.

There is no representation by Baytex that actual results achieved will be the same in whole or in part as those referenced in the forward-looking statements. The future oriented financial information and forward-looking statements are made as of December 7, 2022 and Baytex disclaims any intent or obligation to update publicly any forward-looking statements, whether as a result of new information, future events or results or otherwise, other than as required by applicable securities laws.

All amounts in this presentation are stated in Canadian dollars unless otherwise specified.

Investment Highlights

High Quality and Diversified Oil Portfolio

- ~ 10 or more years of projected drilling inventory in each of our core areas (Viking, Eagle Ford and Canadian heavy oil)
- Strong capital efficiencies across portfolio

Clearwater Development and Exploration

- > 125 net prospective sections in one of the most profitable plays
- Peavine production increased to 10,000 bbl/d in October
- Continued appraisal drilling at Peavine and Seal

Meaningful Free Cash Flow Generation

- Five-year plan (2022-2026) generates ~ $3.1 billion of free cash flow[1] at US$80 WTI
- > 50% of free cash flow over the five-year plan to be returned to shareholders at US$80 WTI

Shareholder Returns

- 25% of free cash flow to share buybacks commenced May 2022
- 50% of free cash flow to share buybacks at $800 million net debt
- 75% of free cash flow to direct shareholder returns at $400 million net debt

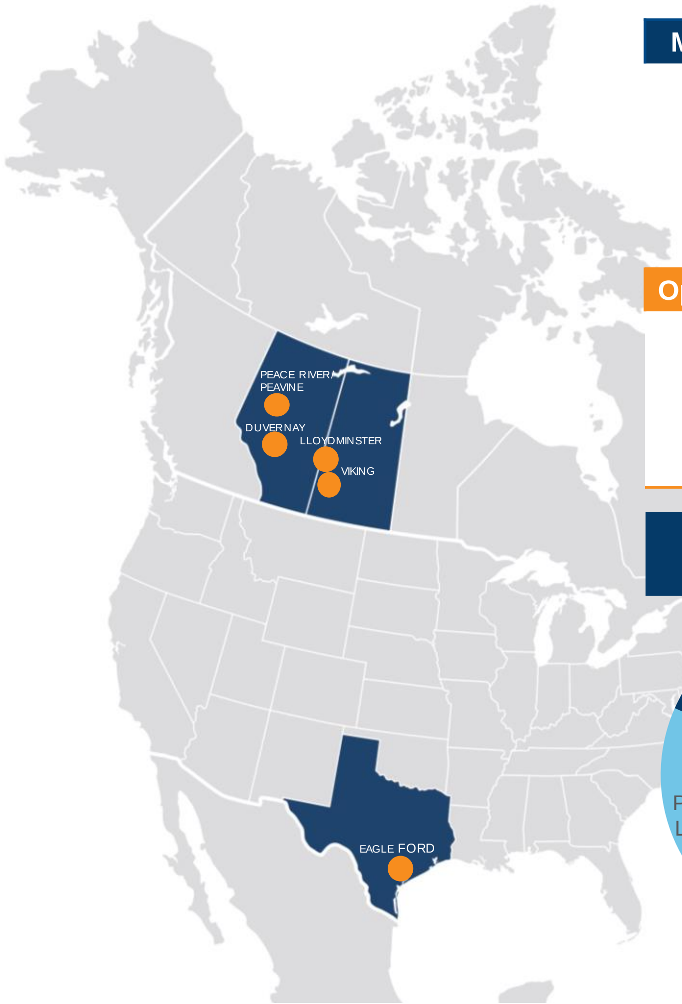
Environmental Stewardship

- Delivered 52% reduction in GHG emissions intensity through 2021, relative to 2018 baseline; targeting 65% reduction by 2025
- Committed to reducing 2020 end of life well inventory of ~4,500 wells to zero by 2040

(1) Non-GAAP financial measure that is not a standardized financial measure under IFRS and may not be comparable to similar measures disclosed by other issuers. See "Specified Financial Measures" in the Q3/2022 MD&A for information related to this non-GAAP financial measure, which information is incorporated by reference into this presentation.

(2) Capital management measure. See the "Specified Financial Measures" in this presentation for information related to this measure.

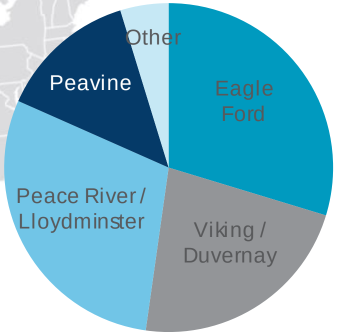
Corporate Profile



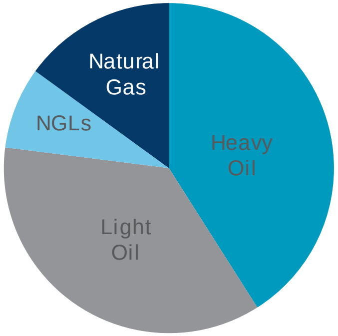
Market Summary	
Ticker Symbol	TSX: BTE
Average Daily Volume (1)	7 million
Shares Outstanding (2)	546 million
Market Capitalization / Enterprise Value (2)	$3.7 billion / $4.8 billion

Operating Statistics	
Production (Gross W.I.) (3)	86,000 – 89,000 boe/d
Production Mix (3)	85% liquids
E&D Expenditures (3)	$575 - $650 million
Reserves – 2P Gross (4)	451 mmboe

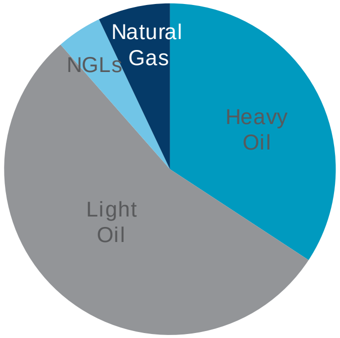
Production by Core Area (5)



Production by Commodity (5)



Revenue by Commodity (6)



(1) Average daily trading volumes for November 2022. Volumes are a composite of all exchanges in Canada.
(2) Enterprise value based on shares outstanding and closing share price on the Toronto Stock Exchange on December 1, 2022 and net debt as at September 30 , 2022.
(3) Production, production mix, and exploration and development ("E&D") expenditures represents 2023 guidance.
(4) Baytex reserves as at December 31, 2021 as evaluated by McDaniel & Associates Consultants Ltd.
(5) Production (Gross W.I.) composition based on 2023 guidance. Heavy oil includes Peace River, Lloydminster and Peavine.
(6) Revenue by commodity composition based on nine-month 2022 actual results.

YTD 2022 Highlights

Meaningful Free Cash Flow, Strong Clearwater Drilling and Share Buy-Back Program Initiated

	YTD 2022 Highlights
Meaningful Free Cash Flow and Debt Reduction	▪ Generated free cash flow(1) of $478 million in the first nine months of 2022 ($0.85 per basic share) ▪ Reduced net debt(2) by 21% to $1.1 billion, from $1.4 billion at YE 2021
Materially Advanced Clearwater Development at Peavine	▪ October 2022 production of 10,000 bbl/d, up from 3,150 bbl/d in Q1/2022 ▪ First 4 wells from H2/2022 drilling program generated average 30-day initial production rates of 1,100 bbl/d per well ▪ Shift to tighter lateral spacing could potentially lead to a 20% increase in prospective drilling inventory
2022 Guidance	▪ Production of ~ 84,000 boe/d expected to deliver 5% annual production growth (6% on a per-share basis) ▪ Expect to exit 2022 producing 87,000 to 88,000 boe/d ▪ Exploration and development expenditures ~ 45% of adjusted funds flow
Share Buyback Program	▪ Direct shareholder returns initiated in May with 25% of free cash flow allocated to share buybacks ▪ Repurchased 23.5 million shares through November 2022, 4.1% of shares outstanding

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(2) Information related to this capital management measure is available in the Q3/2022 MD&A under the heading “Specified Financial Measures” and is incorporated by reference into this presentation.

ESG Highlights

GHG Emission Reduction

52% reduction in GHG emissions intensity through 2021, relative to 2018 baseline; 65% target in place

Safety

25% reduction in total recordable injury frequency in 5 years

Gas Conservation

> 95% routine gas conservation in Peace River in 2021

Indigenous Relations

Recent agreements with Peavine Métis Settlement

Spill Volumes

59% reduction in reportable spill volumes over 5 years

Gender Diversity

Target of 30% women Board members by 2023 Shareholder meeting

Abandonment & Reclamation

Reduce 2020 inactive well inventory of ~ 4,500 wells to zero by 2040

Water

Initiated water recycle projects in Kerrobert, Viking and Duvernay

Maintaining Capital Discipline and Driving Meaningful Free Cash Flow

- Production guidance (at mid-point) of 87,500 boe/d represents:
  - 4% annual production growth
  - 8% production per share growth[(1)]
  - Strong operating momentum and production growth on our Clearwater lands
- Exploration and development expenditures represents:
  - Strong capital efficiency of $19,500/boe/d
  - Program fully funded at US$55 WTI
- Capital allocation:
  - 65% light oil; 35% heavy oil (including 15% directed to the Peavine Clearwater)
- Based on the forward strip[(2)], we expect to generate ~ $450 million of free cash flow[(3)] in 2023

2023 Guidance	
E&D Expenditures	$575- 650 million
Production	86,000 - 89,000 boe/d
Oil and NGLs	85%

Operating Area	Net Wells Onstream	CapEx ($MM)[(4)(5)]
Viking	144	$205
Eagle Ford	15	$130
Heavy Oil [(6)]	50	$125
Clearwater	33	$85
Pembina Duvernay	6	$70
Total		$615

(1) Includes impact of share buyback program.

(2) 2023 commodity prices: WTI - US$76/bbl; WCS differential - US$25/bbl; MSW differential – US$3/bbl, NYMEX Gas - US$5.70/mmbtu; AECO Gas - $4.75/mcf and Exchange Rate (CAD/USD) - 1.34.

(3) Non-GAAP financial measure that is not a standardized financial measure under IFRS and may not be comparable to similar measures disclosed by other issuers. See "Specified Financial Measures" in the Q3/2022 MD&A for information related to this non-GAAP financial measure, which information is incorporated by reference into this presentation.

(4) Approximate 2023 capital spending by quarter: Q1-34%, Q2-17%, Q3-32%, Q4-17%.

(5) Represents mid-point of 2023 guidance range.

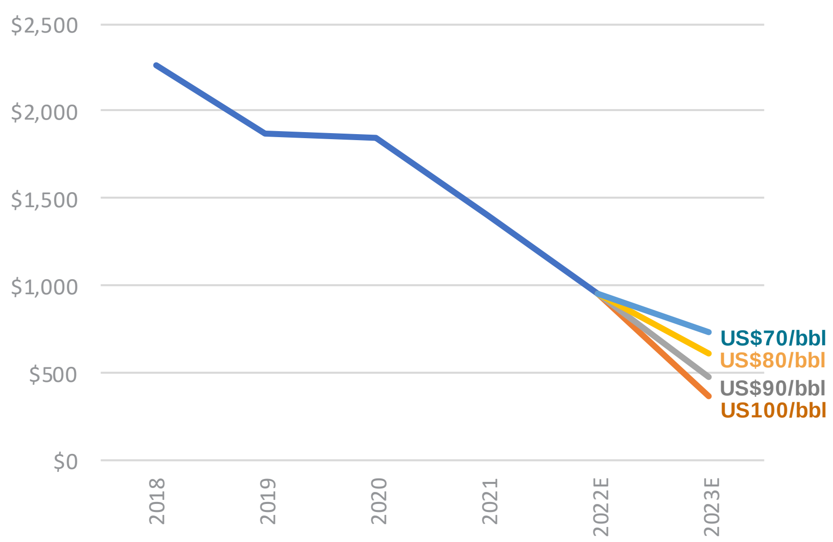
(6) Heavy oil includes Peace River Bluesky development and Lloydminster.

Committed to Maintaining Strong Financial Flexibility

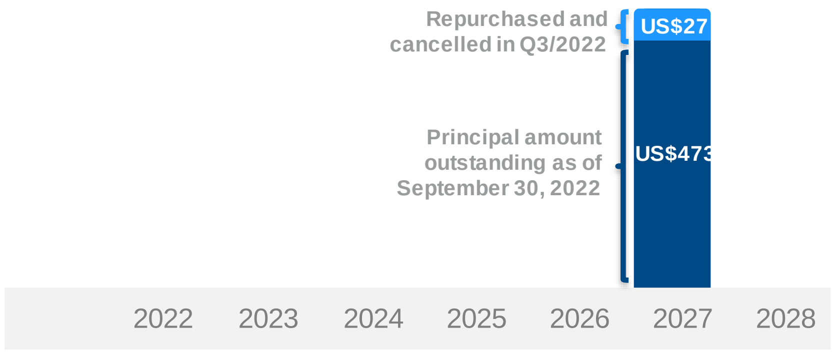
- **Strong liquidity**
- **Credit facilities extended to 2026 and increased to US$850 million**
- **Redeemed US$200 million long-term notes due 2024 on June 1st**

Net Debt[(1)] (September 30, 2022)	$ millions
Credit facilities [(2)]	$450
Long-term notes	$648
Long-term debt	$1,098
Working Capital	$16
Net Debt	$1,114

Net Debt[(1)] Profile ($ millions)



Long-Term Notes Maturity Schedule[(3)] ($ millions)



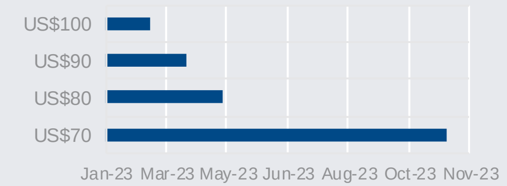
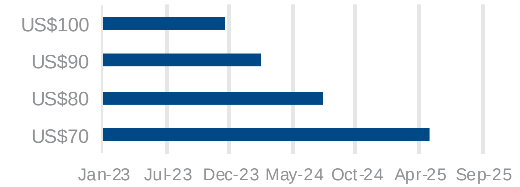
(1) Information related to this capital management measure is available in the Q3/2022 MD&A under the heading "Specified Financial Measures" and is incorporated by reference into this presentation.

(2) Revolving credit facilities total US$850 million and mature April 2026. The revolving credit facilities are not borrowing base facilities and do not require annual or semi-annual reviews.

(3) S&P corporate rating "B+" and senior unsecured debt rating "BB-" ; Fitch corporate rating "B+" and senior unsecured debt rating "BB-"; Moody's corporate rating "B1" and senior unsecured debt rating "B3".

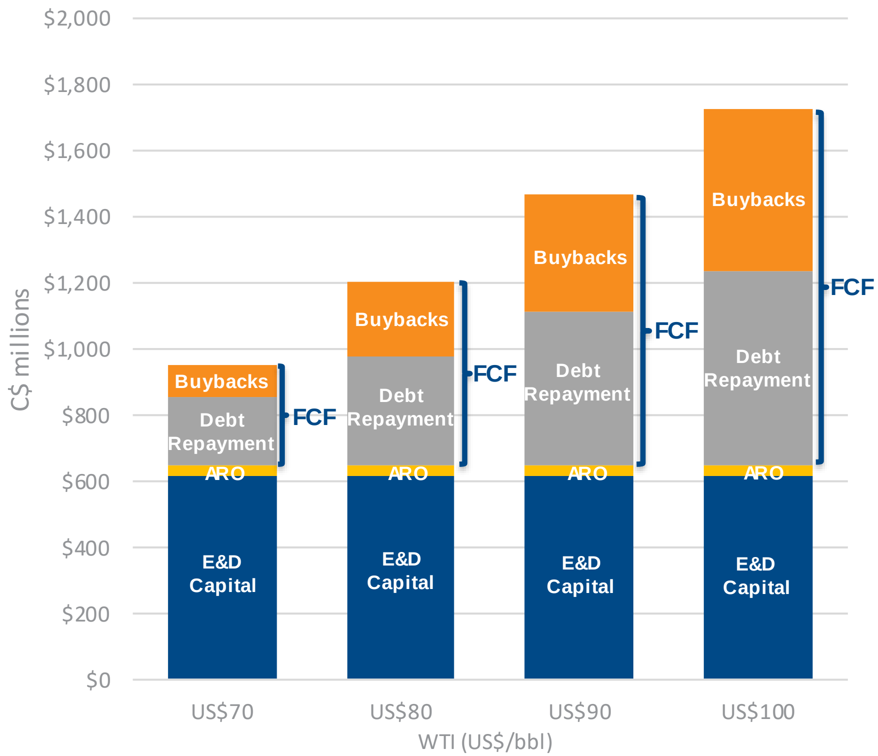
Shareholder Return Framework

Committed to Enhancing Direct Shareholder Returns

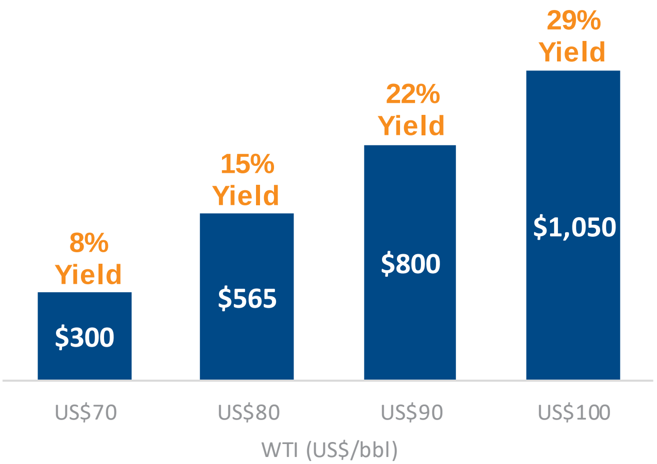
	Free Cash Flow Allocation	Action	Status
Phase 1 ✓	• 100% of free cash flow to debt repayment until reaching $1.2 billion net debt	• Reduced net debt by $648 million from December 2020 to May 2022	• Achieved May 2022
Phase 2 **In Progress**	• 75% of free cash flow to debt repayment until reaching $800 million net debt (1x net debt to EBITDA at US$55 WTI) • 25% of free cash flow to share buybacks	• Anticipate exiting 2022 with net debt < $1 billion • Repurchased 23.5 million shares through November 2022, 4.1% of float	• Anticipated timing to reach $800 million net debt level: 
Phase 3	• 50% of free cash flow to debt repayment until reaching $400 million net debt (1x net debt to EBITDA at US$45 WTI) • 50% of free cash flow to share buybacks		• Anticipated timing to reach $400 million net debt level: 
Phase 4	**75% of free cash flow to direct shareholder returns**		

2023 Free Cash Flow Generation and Shareholder Return Potential

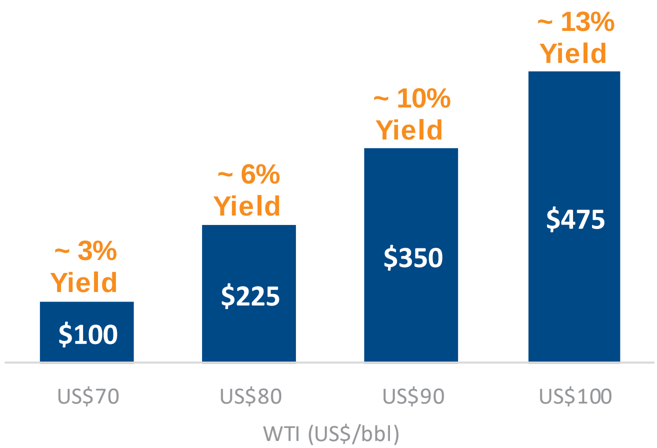
Targeted Free Cash Flow(1)(2)(3) to Share Buybacks



2023 Free Cash Flow ($ millions)(1)(4)



2023 Free Cash Flow Allocated to Share Buybacks ($ millions)(5)



(1) Non-GAAP financial measure that is not a standardized financial measure under IFRS and may not be comparable to similar measures disclosed by other issuers. See "Specified Financial Measures" in the Q3/2022 MD&A for information related to this non-GAAP financial measure, which information is incorporated by reference into this presentation.

(2) For illustrative purposes only and should not be relied upon as indicative of future results. Baytex's actual results may vary.

(3) 2023 pricing assumptions at each assumed WTI level - WCS differential – US$23/bbl; MSW differential – US$3/bbl, NYMEX Gas - US$4.50/mmbtu; AECO Gas - $4.50/mcf and Exchange Rate (CAD/USD) - 1.35.

(4) Free cash flow yield represents the estimated 2023 free cash flow divided by market capitalization as at December 1, 2022.

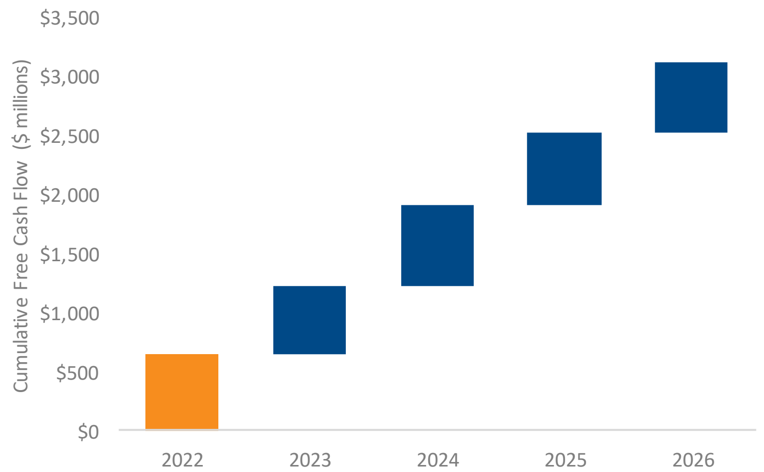
(5) Free cash flow allocated to buybacks reflects the timing of achieving $800 million net debt target and moving to Phase 3 of Shareholder Return Framework (50% of free cash flow allocated to buybacks). Yield for share buybacks represents the estimated 2023 free cash flow allocated to share buybacks divided by market capitalization as at December 1, 2022.

5-Year Plan @ US$80/bbl Generates $3.1B Cumulative Free Cash Flow

Highlights of 5-Year Plan

- **$3.1 billion cumulative free cash flow[1]**
- **Exploration and development expenditures represent ~ 50% of adjusted funds flow**
- **2-4% annual production growth**
- **Adjusted funds flow per share[1] increases ~ 50% (2022 to 2026)**

Free Cash Flow[1] Profile (after-tax)



	Production (boe/d)	Adjusted Funds Flow[2] ($ MM)	Adjusted Funds Flow[2] ($ per share)	E&D Expenditures ($MM)	ARO / Leasing Expenditures ($MM)	After-Tax Free Cash Flow[1] ($MM)
2022	84,000	$1,187	$2.12	$515	$22	$650
2023	87,500	$1,208	$2.27	$615	$28	$565
2024	91,000	$1,345	$2.73	$620	$30	$695
2025	93,000	$1,270	$2.83	$635	$30	$605
2026	95,000	$1,285	$3.15	$650	$30	$605

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(2) Information related to this capital management measure is available in the Q3/2022 MD&A under the heading "Specified Financial Measures" and is incorporated by reference into this presentation. Adjusted funds flow per share assumes share buybacks occur under the announced Shareholder Return Framework with an assumed share price equating to a 3.5x EV/DACF multiple.

(3) For illustrative purposes only and should not be relied upon as indicative of future results. Baytex's actual results may vary. Budget and forecast beyond 2023 have not been finalized and are subject to a variety of factors including prior year's results.

(4) Year one (2022) based on nine-month 2022 actual results and forward strip commodity prices for the balance of the year. Full-year 2022 commodity prices: WTI - US$95/bbl; WCS differential - US$19/bbl; MSW differential – US$2/bbl, NYMEX Gas - US$6.55/mmbtu; AECO Gas - $5.50/mcf and Exchange Rate (CAD/USD) - 1.30.

(5) Years two through five (2023 to 2026) based on the following commodity price assumptions: WTI - US$80/bbl; WCS differential – US$23/bbl for 2023, US$12.50/bbl for 2024-2026; MSW differential – US$3/bbl, NYMEX Gas - US$4.50/mmbtu AECO Gas - $4.50/mcf and Exchange Rate (CAD/USD) - 1.35.

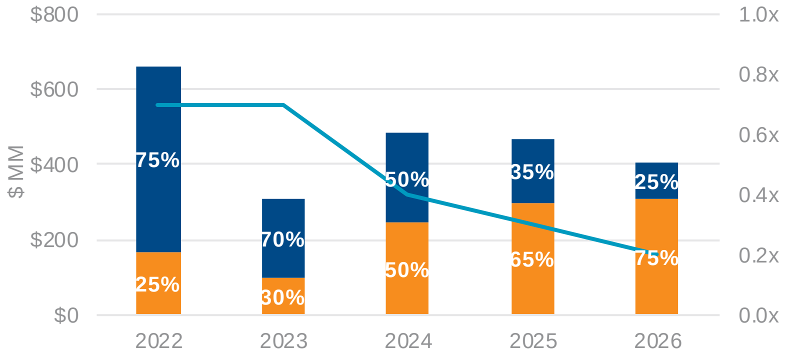
(6) Free cash flow profile for 2023 to 2026 incorporates 30% inflation on exploration and development capital as compared to 2021.

5-Year Plan – Free Cash Flow[1] Sensitivity[2] and Shareholder Return Potential

US$70 WTI

Cumulative Free Cash $2.3B

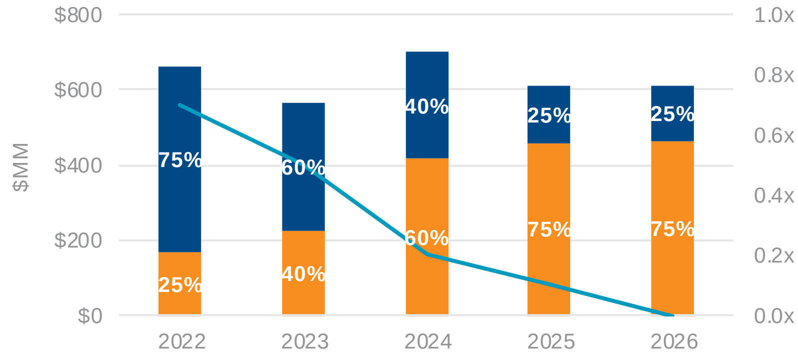
Free Cash Flow to be Returned to Shareholders $1.1B



US$80 WTI

Cumulative Free Cash $3.1B

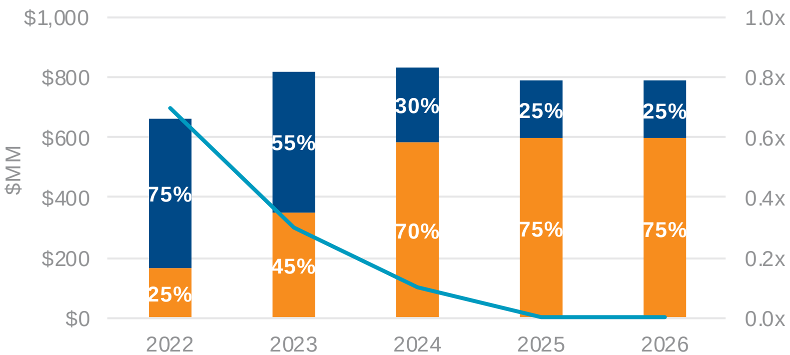
Free Cash Flow to be Returned to Shareholders $1.7B



US$90 WTI

Cumulative Free Cash $3.9B

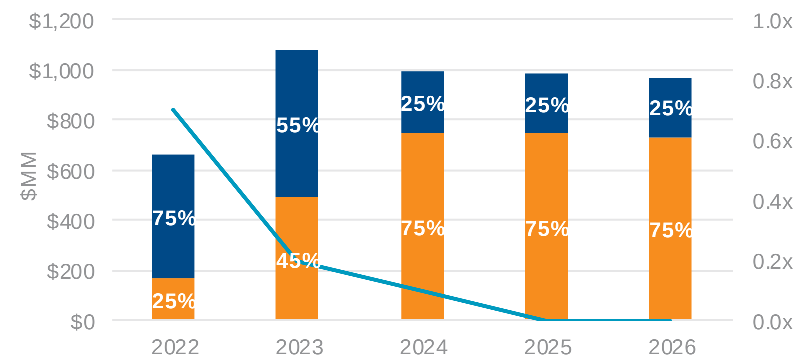
Free Cash Flow to be Returned to Shareholders $2.3B



US$100 WTI

Cumulative Free Cash $4.7B

Free Cash Flow to be Returned to Shareholders $2.9B



Free Cash Flow Returned to Shareholders | Free Cash Flow Allocated to Debt Repayment | Net Debt to Bank EBITDA

(1) Non-GAAP financial measure that is not a standardized financial measure under IFRS and may not be comparable to similar measures disclosed by other issuers. See "Specified Financial Measures" in the Q3/2022 MD&A for information related to this non-GAAP financial measure, which information is incorporated by reference into this presentation.

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(3) Net Debt to EBITDA ratio calculation is based on forecast net debt at each year-end and forecast EBITDA for that particular year.. Net Debt to EBITDA ratio is a capital management measure. See the "Specified Financial Measures" in this presentation for information related to this measure.

Crude Oil Hedge Portfolio

	Q4/2022	H1/2023	H2/2023	Full-Year 2023
WTI Fixed				
Volumes (bbl/d)	10,000	---	---	---
Fixed Price (US$/bbl)	$53.50	---	---	---
WTI 3-Way (1)				
Volumes (bbl/d)	10,500	9,500	9,500	9,500
Average Sold Put / Put / Sold Call (US$/bbl)	$48/$58/68	$62/$78/$96	$62/$78/$96	$62/$78/$96
Total Hedge Volumes (bbl/d)	20,500	9,500	9,500	9,500
Hedge (%) (2)	40%	18%	18%	18%
Basis Differential				
WCS Volumes (bbl/d)	17,000	2,000	2,000	2,000
WCS Price Relative to WTI (US$/bbl)	($12.28)	($19.25)	($19.25)	($19.25)
MSW Volume (bbl/d)	6,750	---	---	---
MSW Price Relative to WTI (US$/bbl)	($3.73)	---	---	---

(1) WTI 3-way contracts consist of a sold put, a bought put and a sold call. In a $62/$78/$96 example, Baytex receives WTI+$16/bbl when WTI is at or below $62/bbl; Baytex receives $78/bbl when WTI is between $62/bbl and $78/bbl; Baytex receives WTI when WTI is between $78/bbl and $96/bbl; and Baytex receives $96/bbl when WTI is above $96/bbl.

(2) Percentage of hedged volumes are based on 2022 annual production guidance (excluding NGL), net of royalties.

2023E Adjusted Funds Flow Sensitivities

Sensitivities	Estimated Effect on Annual Adjusted Funds Flow[1] ($MM)	
	Excluding Hedges	Including Hedges
Change of US$1.00/bbl WTI crude oil	$28	$26
Change of US$1.00/bbl WCS heavy oil differential	$13	$13
Change of US$1.00/bbl MSW light oil differential	$7	$7
Change of US$0.25/mmbtu NYMEX natural gas	$7	$7
Change of $0.01 in the C$/US$ exchange rate	$13	$13

(1) Information related to this capital management measure is available in the Q3/2022 MD&A under the heading "Specified Financial Measures" and is incorporated by reference into this presentation.

Asset Overview

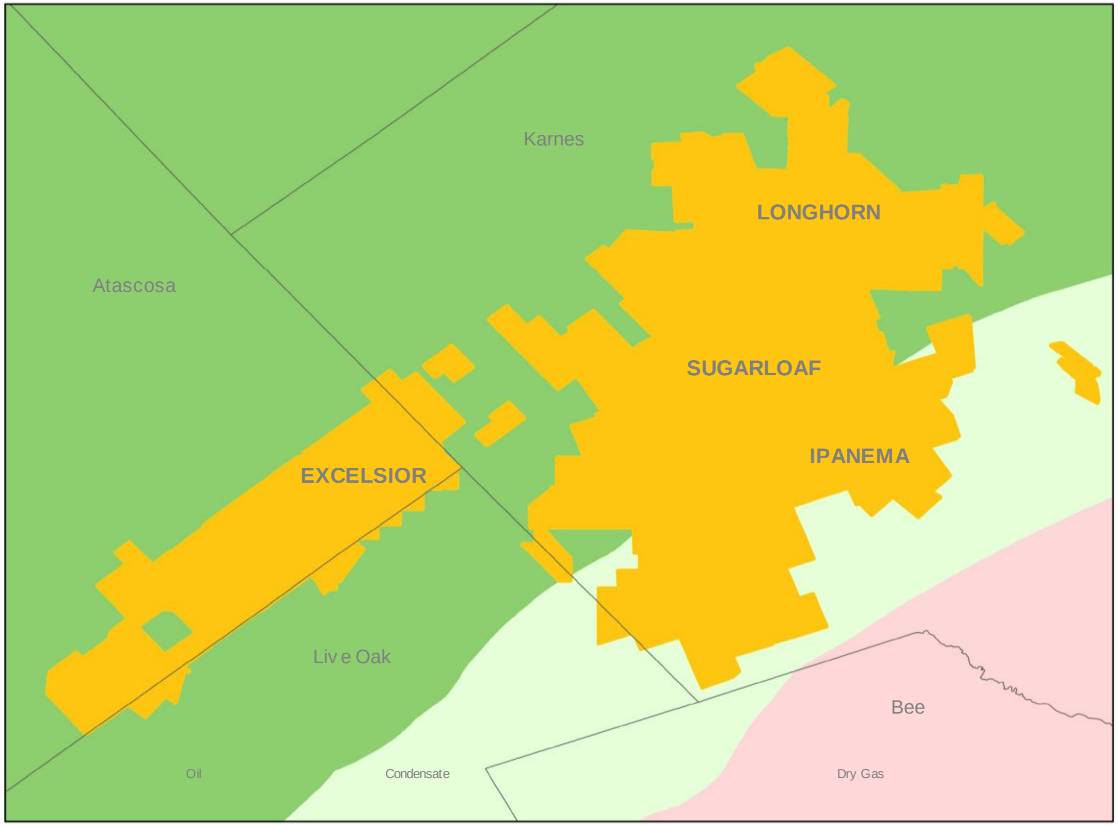
Asset Highlights

Geographic and play diversification with ~ 10 or more years drilling inventory in each core area

	Eagle Ford	Viking	Heavy Oil	Pembina Duvernay
Production *(Gross; 9 Months 2022)*	27,700 boe/d	16,800 boe/d	30,000 boe/d	2,400 boe/d
Oil and NGLs *(Gross; 9 Months 2022)*	81%	88%	93%	83%
2P Reserves [(1)] *(Gross)*	201 mmboe	77 mmboe	132 mmboe	22 mmboe
Asset Highlights	▪ 19,900 net acres in the core of Karnes county with outstanding operating partner, Marathon. ▪ Stable production base with low sustaining capital has driven ~ $1.4 billion of asset level free cash flow since 2016 [(2)]	▪ 419,615 net acres of land in the Viking play ▪ Shallow, light oil resource play with strong netbacks - ~$66/boe at US$80 WTI ▪ Stable production base drives meaningful asset level free cash flow	▪ Dominant land position of 672,640 net acres ▪ Low decline production ▪ Innovative multi-lateral horizontal drilling with top tier capital efficiency ▪ Producing 10,000 bbl/d from the Clearwater at Peavine ▪ Continue Clearwater appraisal drilling at Peavine and Seal	▪ 128,000 net acres of 100% W.I. lands in the Pembina area ▪ Offset development and 14 wells drilled to-date have de-risked ~ 40% of acreage position ▪ Measured delineation planned

(1) Baytex reserves as at December 31, 2021 as evaluated by McDaniel & Associates Consultants Ltd. See “Advisories”.
(2) The term “asset level free cash flow” is a non-GAAP measure. See slide 3 for more information.

Eagle Ford: Core of Karnes County

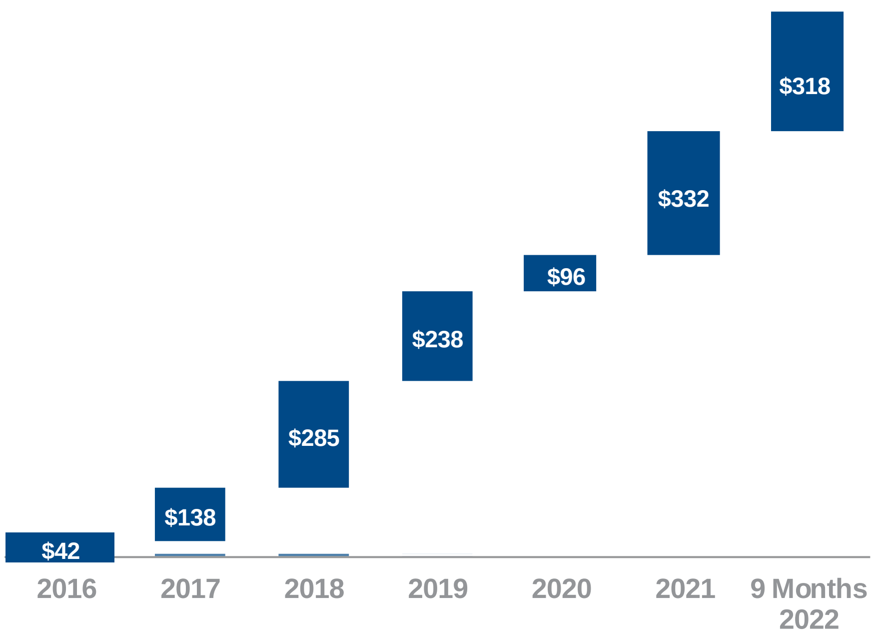


- 19,900 net acres in the core of the Eagle Ford shale in south Texas
- Four AMI's (Longhorn, Sugarloaf, Ipanema and Excelsior) with an average 25% W.I.
- Produced 27,700 boe/d (81% liquids) YTD 2022
- 9 Months 2022 - 56 gross (12.7 net) wells established average 30-day IP rates of ~ 1,500 boe/d per well
- Expect to bring ~ 15 net wells on production in 2023

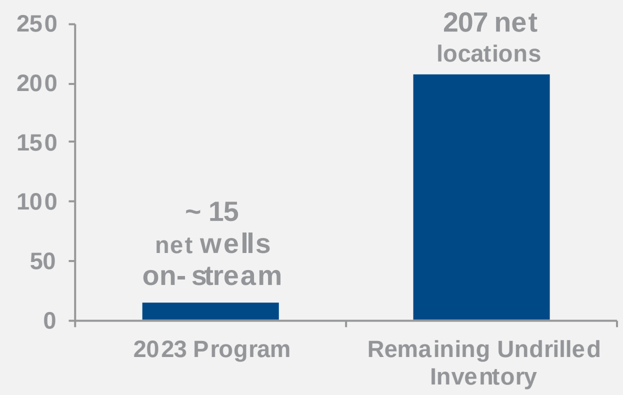
Eagle Ford: Strong Free Cash Flow and Deep Drilling Inventory

Free Cash Flow (1) (C$ millions)

$1.4 billion cumulative asset level free cash flow since 2016



> 10 year drilling inventory (2)



Well Economics (3)

WTI Oil Price	US$70/bbl	US$80/bbl	US$90/bbl
Payout:	11 months	9 months	8 months
IRR:	120%	172%	237%
Recycle Ratio:	3.4x	3.9x	4.4x

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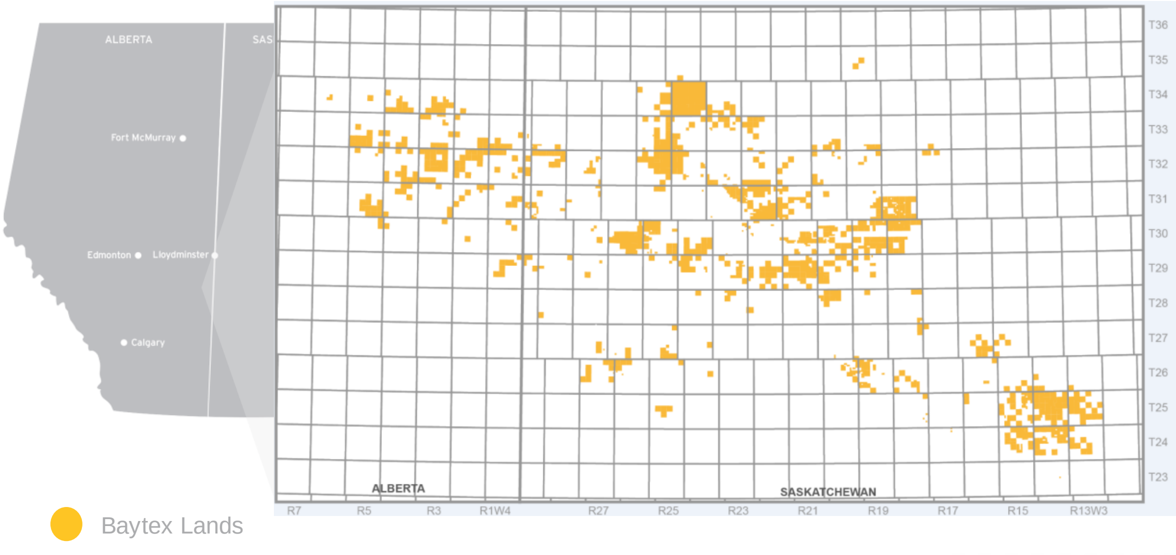
(2) Net locations includes 187 proved plus probable undeveloped reserves locations at year-end 2021 and 37 unbooked future locations, and adjusted for 17 net wells onstream in 2022. See "Advisories"

(3) Individual well economics based on constant pricing and costs, and Baytex's assumptions regarding an expected type curve that uses the following assumptions: well cost $8.3 million (6,000 foot lateral); IP365 - 700 boe/d; EUR – 800 mboe).

Viking Light Oil: 460 Highly Prospective Sections



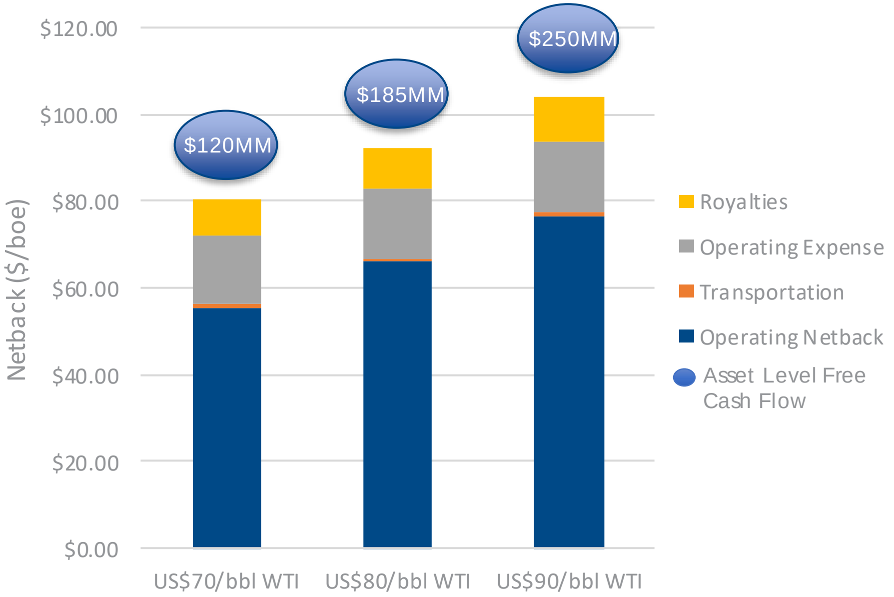
- Shallow (700 m), light oil (36° API) resource play
- Produced 16,800 boe/d (88% oil) YTD 2022
- Strong operating netback[(1)] ~ $66/boe at US$80 WTI
- $250 million of asset level free cash flow[(1)] YTD 2022
- Expect to bring ~ 144 net wells on production in 2023

(1) Non-GAAP financial measure that is not a standardized financial measure under IFRS and may not be comparable to similar measures disclosed by other issuers. See "Specified Financial Measures" in the Q3/2022 MD&A for information related to this non-GAAP financial measure, which information is incorporated by reference into this presentation.

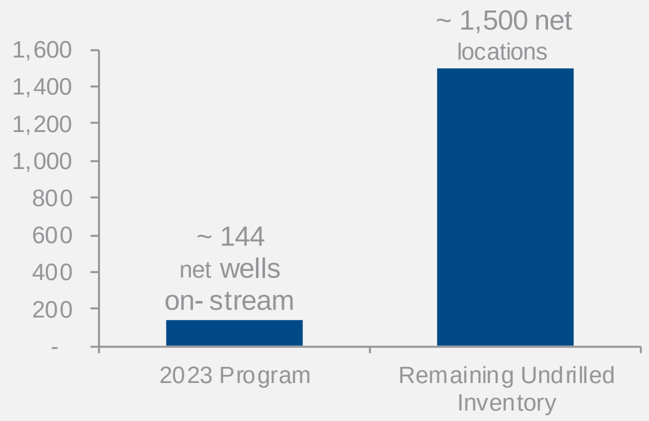
Viking: High Netback Light Oil

High Operating Netback (1) Light Oil ($/boe)

Strong price realizations, low cost structure and high free cash flow (1)



10 year drilling inventory (3)



Well Economics (4)

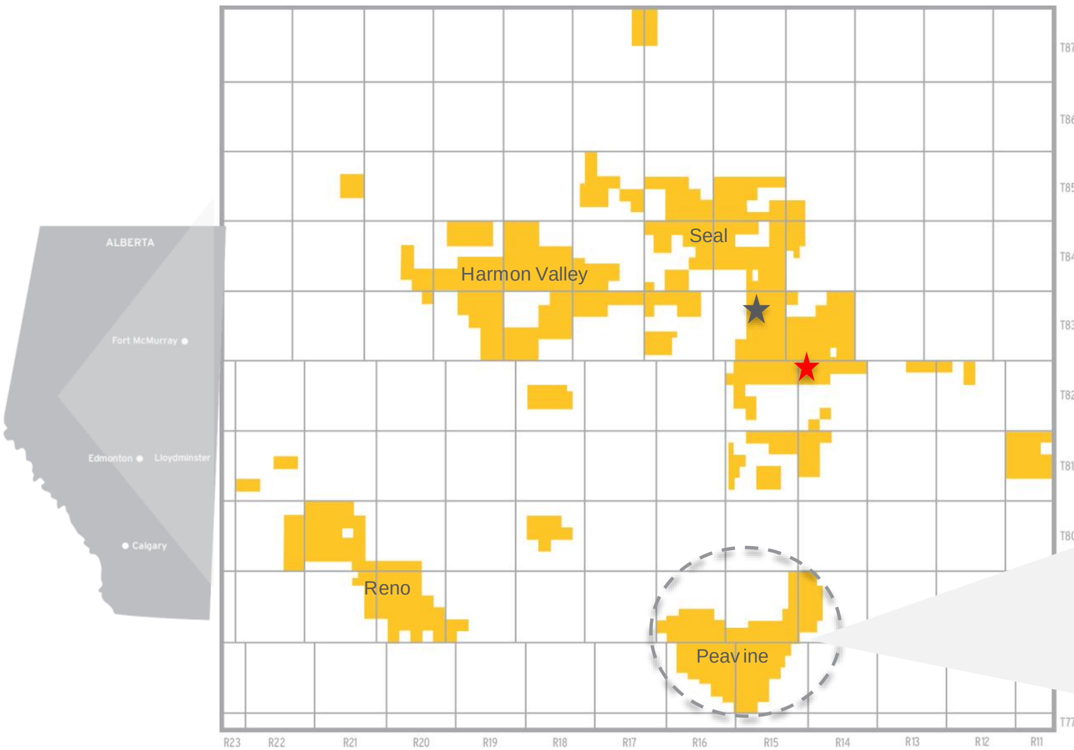
WTI Oil Price	US$70/bbl	US$80/bbl	US$90/bbl
Payout:	17 months	12 months	10 months
IRR:	58%	92%	135%
Recycle Ratio:	1.9x	2.3x	2.6x

(1) Non-GAAP financial measure that is not a standardized financial measure under IFRS and may not be comparable to similar measures disclosed by other issuers. See "Specified Financial Measures" in the Q3/2022 MD&A for information related to this non-GAAP financial measure, which information is incorporated by reference into this presentation.

(2) Net locations includes 1,158 proved plus probable undeveloped reserves locations at year-end 2021 and 490 unbooked future locations and adjusted for 127 net wells onstream in 2022. See "Advisories"

(3) Individual well economics based on constant pricing and costs, and Baytex's assumptions regarding an expected type curve that uses the following assumptions: well cost - $1.3 million; IP365 - 45 boe/d; EUR - 40 mboe. MSW differential assumption US$4/bbl.

Peace River: Innovative Multi-Lateral Development



Baytex Lands ★ Seal Clearwater (Q4/2021) ★ Seal Clearwater (Q4/2022)

- Produced 12,700 boe/d YTD 2022 (84% oil)
- Dominant 500 net sections
- 10 net Bluesky multi-lateral wells planned for 2023
- Long life polymer flood at Seal

Clearwater

- Strategic agreements with Peavine Métis Settlement cover 80 contiguous sections
- Produced 8,200 boe/d (100% oil) in Q3/2022
- Continue exploration and appraisal at Peavine and Seal
- Expect to bring 33 net Clearwater wells onstream in 2023 (31 net wells at Peavine, 2 net wells at Seal)

Clearwater: Superior Well Performance and Economics

Clearwater Lands

- > 500 net sections in the NW Clearwater fairway with > 125 prospective for Spirit River (Clearwater equivalent)
- 50 net sections at Peavine de-risked
- Initiated down-spacing (moving to 5-wells per section) which offers a potential 20% increase in our future Peavine Clearwater drilling inventory, to over 250 locations
- Successful Clearwater exploration well on Seal legacy lands in late 2021 with follow-up well in Q4/2022

Operations Update

- Production increased from zero at the beginning of 2021 to 10,000 bbl/d in October 2022 from 24 producing wells
- First four wells of H2/2022 drilling program generated 30-day initial production rates of 1,100 bbl/d per well
- 13 Baytex wells rank in the top 15 Clearwater wells drilled to-date on an initial rate basis; outperforming Baytex type curve assumptions

Top 15 Clearwater Wells (1)

No.	UWI	Current Operator	Peak Calendar Rate (bbl/day)
1	100/01-30-078-15W5	BAYTEX	1,201
2	102/01-30-078-15W5	BAYTEX	1,109
3	102/06-27-078-16W5	BAYTEX	1,078
4	102/09-30-078-15W5	BAYTEX	1,075
5	100/03-27-078-16W5	BAYTEX	1,052
6	100/08-30-078-15W5	BAYTEX	1,037
7	103/08-30-078-15W5	BAYTEX	973
8	102/11-31-078-15W5	BAYTEX	910
9	102/03-27-078-16W5	BAYTEX	864
10	100/06-31-078-15W5	BAYTEX	861
11	100/13-27-078-16W5	BAYTEX	840
12	102/11-27-078-16W5	BAYTEX	786
13	100/06-27-078-16W5	BAYTEX	748
14	102/12-34-074-25W4	HWX (CVE)	733
15	103/15-15-073-25W4	CNRL	730

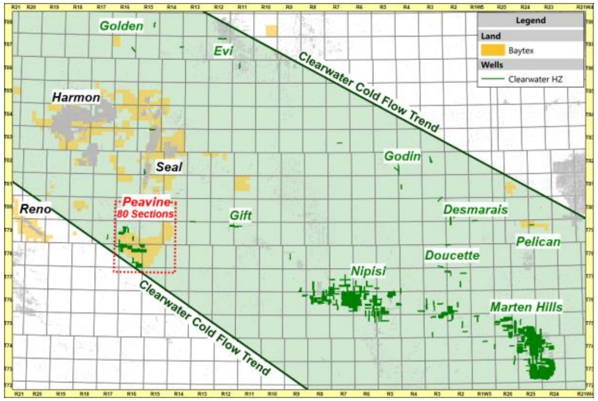
Well Economics (2)

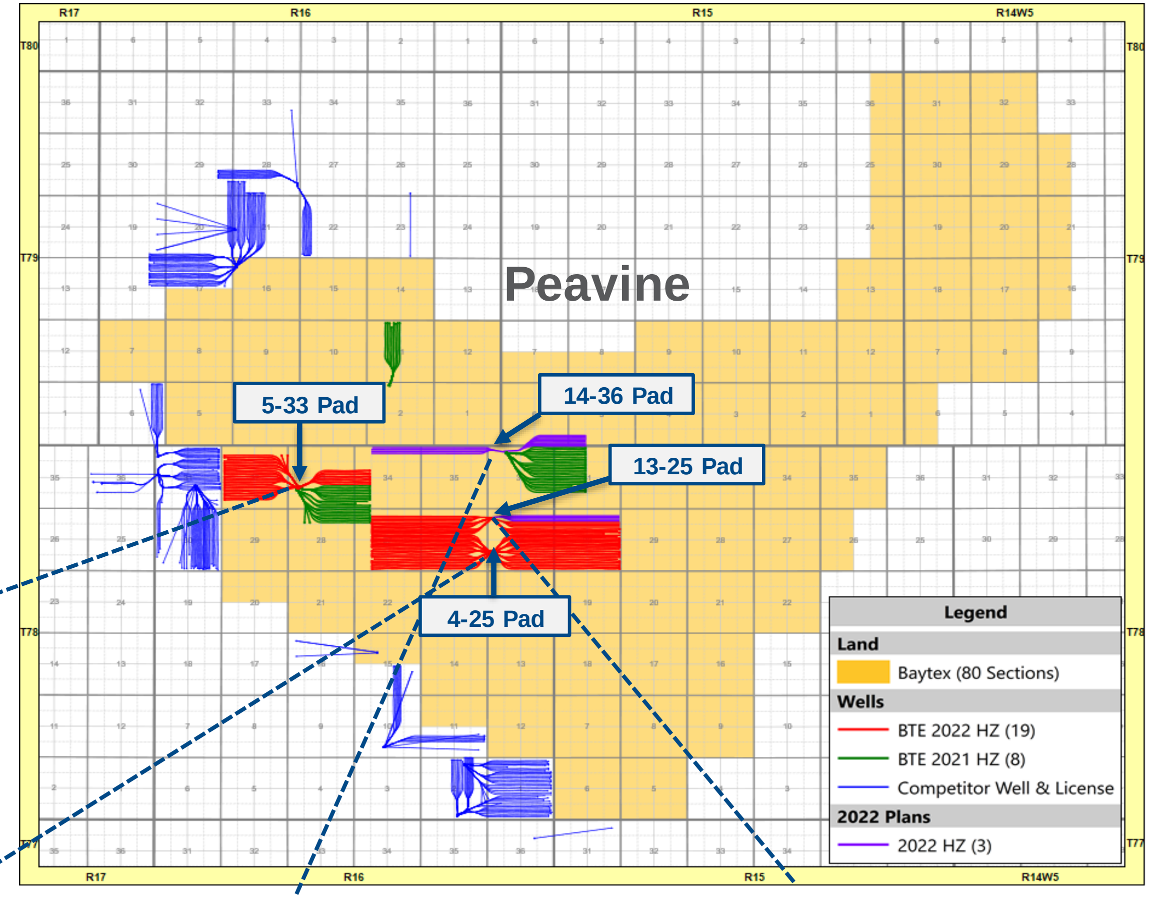
WTI Oil Price	US$70/bbl	US$80/bbl	US$90/bbl
Payout:	7 months	5 months	4 months
IRR:	237%	483%	> 500%
Recycle Ratio:	3.3x	4.1x	4.8x

(1) Public data obtained from GeoScout. Baytex's two most recent wells (102-09-30 and 102/11-27) represent an estimate of the calendar rates for the month of October.

(2) Individual well economics based on constant pricing and costs, and Baytex's assumptions regarding an expected type curve that uses the following assumptions: development well cost - $1.9 million; IP30 - 335 bbl/d, IP 365 - 180 bbl/d; EUR – 170 mboe; WCS differential assumption US$17.50/bbl in year one, US$12.50/bbl thereafter.

Clearwater: H1/2022 Program Accelerates Development





5-33 Pad

- Q1/2022 – 4 wells onstream in March/April, with IP30's of 300-450 bbl/d per well
- September production ~ 1,600 bbl/d

4-25 Pad

- 10 ERH wells drilled in 2022
- 5 wells generated IP30's > 1,000 bbl/d per well
- September production ~ 6,700 bbl/d

14-36 Pad

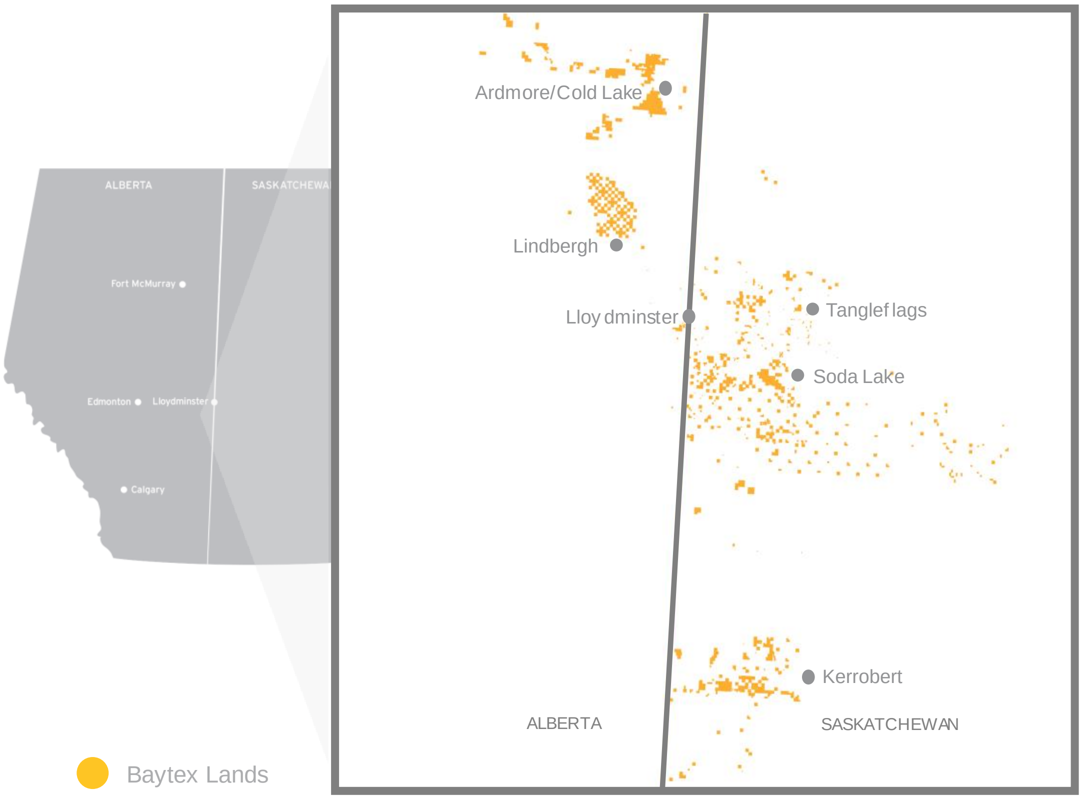
- September production 800 bbl/d
- IP30 averaged 890 bbl/d per well
- 2 wells (including 1 ERH) in H2/2022

13-25 Pad

- 6 ERH wells in H2/2022, 4 of the 6 wells on production in October

"ERH" refers to extended reach horizontal wells and are comprised of four 2-mile long laterals versus a traditional design of eight 1-mile long laterals.

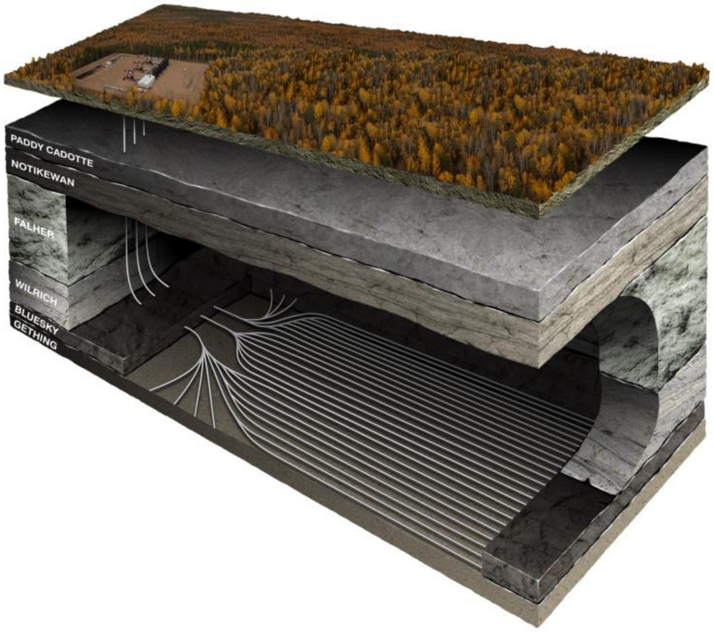
Lloydminster: Significant Land Position and Drilling Inventory



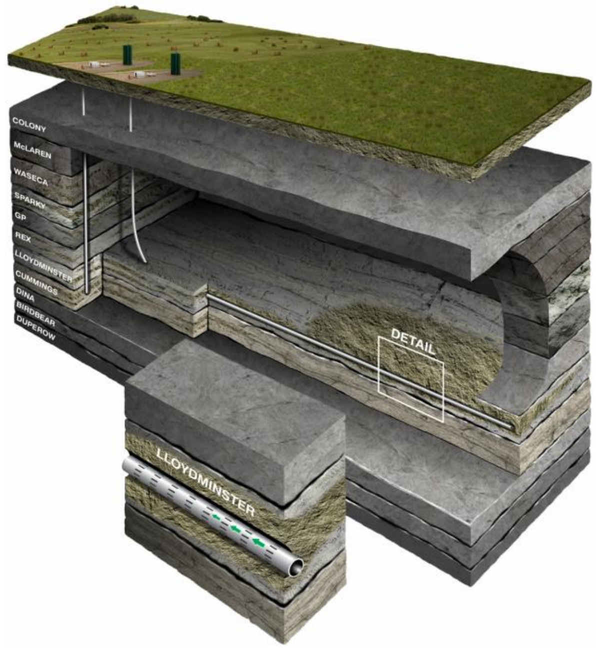
- Produced 11,100 boe/d YTD 2022 (97% oil)
- Strong capital efficiencies
- Applying multi-lateral horizontal drilling and production techniques
- Long-life water and polymer floods at Soda Lake and Tangleflags
- Expect to bring ~ 40 net wells on production in 2023

Heavy Oil Innovation

Peace River
Multi-Lateral Horizontal



Lloydminster
Horizontal



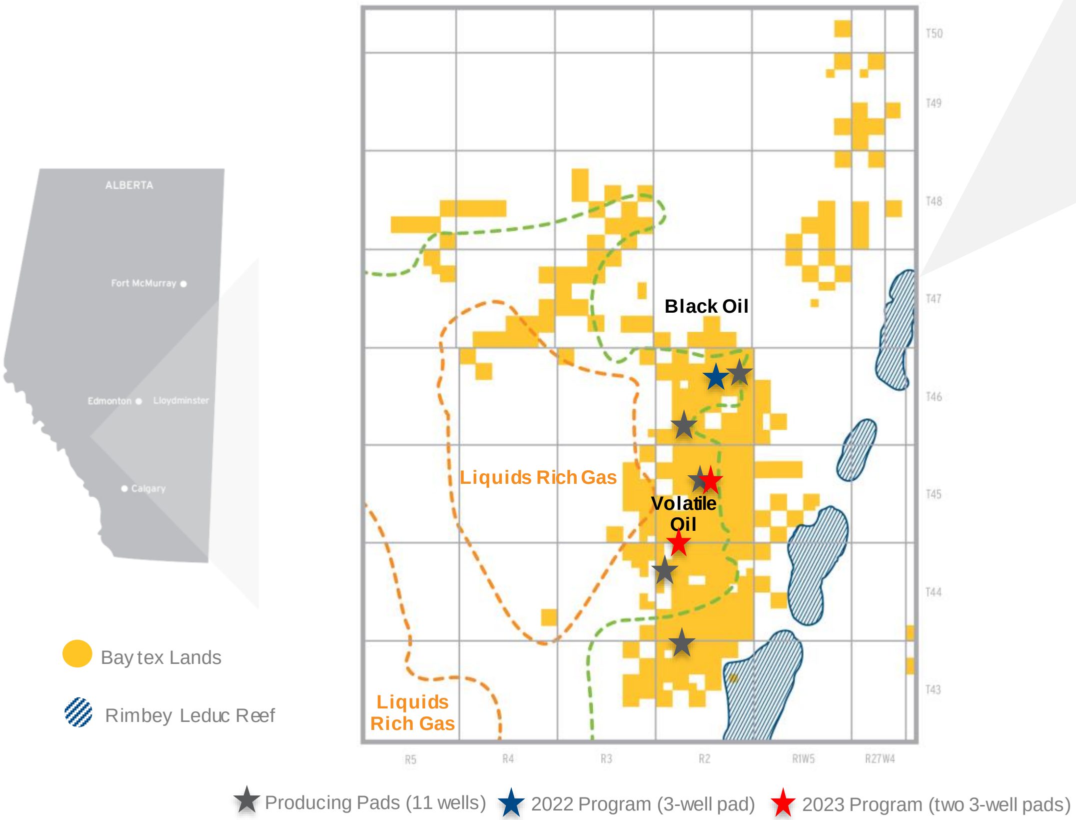
Well Economics (1)

WTI Oil Price	US$70/bbl	US$80/bbl	US$90/bbl
Payout:	16 months	12 months	9 months
IRR:	75%	121%	181%
Recycle Ratio:	2.9x	3.5x	4.1x

WTI Oil Price	US$70/bbl	US$80/bbl	US$90/bbl
Payout:	13 months	10 months	8 months
IRR:	113%	177%	259%
Recycle Ratio:	2.6x	3.2x	3.8x

(1) Individual well economics based on constant pricing and costs, and Baytex's assumptions regarding an expected type curve that uses the following assumptions: Peace River Bluesky: well cost - $3.2 million; IP 365 - 175 boe/d; EUR – 270 mboe; Lloydminster single lined horizontal / multi-lateral: well cost - $1.3 million ; IP365 - 90 boe/d; EUR – 100 mboe. WCS differential assumption US$17.50/bbl in year one, US$12.50/bbl thereafter.

Pembina Area Duvernay Light Oil: Emerging Resource Play



Pembina Duvernay

- Continue to advance the delineation of the Pembina Duvernay Shale
- ~ 200 sections of 100% WI lands
- 14 wells drilled to date have delineated a minimum of 100-125 sections
- Produced 2,400 boe/d (83% liquids) YTD 2022
- 3-well pad drilled in 2022 on northern edge of land base tracking to type well forecast for that region with 90-day initial production rates of ~ 700 boe/d per well
- Expect to bring 6 net wells on production in 2023

High Quality Oil Development

	Eagle Ford	Viking	Peace River	Lloydminster	Pembina Duvernay
Formation	Lower Eagle Ford Upper Eagle Ford Austin Chalk	Viking	Bluesky Clearwater	Mannville Group	Duvernay
Depth (metres)	3,300-3,900	700	550-800 (Bluesky) 500-600 (Clearwater)	350-800	2,200-2,400
Oil API	Oil: 40-45° Condensate: 44-55°	36°	9-12° (Bluesky) 12-13° (Clearwater)	10-16°	42-44°
Porosity	4.6% - 9%	23%	24-30% (Bluesky) 21-30% (Clearwater)	30%	3% - 6%
Permeability	0.33 - 0.41 millidarcies	0.5 - 50 millidarcies	1-10 darcies (Bluesky) 0.01-1 darcies (Clearwater)	0.5 - 5 darcies	10 nanodarcy
Completion	Plug and perf	Pin point coil	Open hole multi-lateral	Horizontal slotted liner / open-hole multi-lateral	Plug and perf
Expected Well Costs (drill, complete, equip and tie-in)	$8.3 million 6,000 foot lateral	$1.3 million	$3.2 million (Bluesky) $1.9 million (Clearwater)	$1.3 million	$9.5 million
Land - gross (net) sections	122 (31)	763 (656)	582 (580)	637 (491)	200 (200) Pembina area
Reserves at YE 2021 (mmboe)					
Proved developed producing	70	20	17	10	3
Proved	150	51	28	26	12
Proved plus probable	201	77	48	84	22
Drilling inventory (risked) at YE 2021 – net locations (booked/unbooked)	187 / 37	1,158 / 490	98 / 334	145 / 423	29 / 231

Environment, Social and Governance (ESG)

ESG at Baytex

As a **responsible** energy company, we take a **sustainable** approach to managing and developing our business into the future. We aspire to create an organization that **future generations** will be proud to be a part of.

OUR VALUES

We have built into our culture a strong connection and sense of responsibility to our communities and stakeholders. Our core values of sustainability, connection, and empowerment guide our actions and decision-making as a responsible energy company.

SUSTAINABILITY

For us, sustainability means managing our ESG impacts, strengthening our corporate resilience, and remaining relevant into the future.

CONNECTION

We believe that fostering positive relationships and strong connections, inside and outside our company, are key to developing the innovative solutions needed to thrive as a company and as a society.

EMPOWERMENT

We recognize that individual decisions and actions determine our collective culture and, ultimately, the success of our company. In all areas of our business, we foster a culture of empowerment and shared accountability.

OUR ESG VISION

Baytex will be a leader in the responsible production of energy the world needs for the future.

OUR APPROACH

» We believe environmental, social, and governance performance is key to our long-term success.
» We focus on pragmatic and impactful opportunities to continuously improve our operating practices.
» We set meaningful targets to improve our performance and have a track record of delivering on our commitments.
» We monitor our impacts and provide transparent disclosures to our stakeholders.

How Focusing on ESG Creates Value

By incorporating environmental, social and governance factors into our business and reporting on our performance, we create value for shareholders and remain focused on advancing a **responsible energy future**.

	ENVIRONMENT	SOCIAL	GOVERNANCE
Our Focus	» Responsibly develop our assets » Reduce our GHG emissions intensity » Restore inactive sites for future generations » Reduce freshwater use	» Create a culture of safety » Engage our employees » Support diversity in our workforce » Be a good neighbour	» Ensure effective Board leadership » Be ethical, transparent, and accountable » Tie compensation to key ESG matters
How it Contributes to Company Value Creation	» Improves the reliability of our operations and reduces costs » Helps to build trust with regulators and stakeholders and maintains social licence » Reduces corporate end-of-life liability » Supports decarbonization of our operations	» Supports the consistent and safe execution of our business plan and enhances company performance » Maintains social licence and enables growth in our operations by reducing non-technical project delays	» Sets strategic direction and improves decision-making » Enables shareholders and stakeholders to make informed decisions » Encourages a culture of continuous improvement

Our ESG Scorecard

Continual improvement is an important element of our culture. We set short and long-term targets to address our impact on air, water, land and people. Each year, we report on our progress towards those targets.

OUR TARGETS	2021 PROGRESS	LOOKING FORWARD
GHG EMISSIONS By 2025, **reduce our emissions intensity by 65%** from our 2018 baseline	**Reduced our emissions intensity by 52%** compared to our 2018 baseline	Execute our first annual **GHG mitigation budget** Develop an **emissions reduction pathway** to 2025 and beyond
ABANDONMENT AND RECLAMATION Restore our 2020 end-of-life well inventory through our **"4,500 Wells by 2040"** initiative, returning them to their pre-disturbance productivity	Completed 198 well abandonments – **the most in company history**	Five-year commitment to **invest $100 million from 2022 to 2026,** or approximately $20 million per year
WATER USE By 2022, **evaluate and test new methods** to reduce the freshwater use intensity of our operations	Pilot projects resulted in **40% of completions water** coming from non-fresh water sources	Develop an **internal water management framework** that prioritizes reducing freshwater use
ENGAGEMENT AND DIVERSITY By 2022, expand our baseline to **include multiple dimensions of diversity** and enhance our processes to measure **employee engagement**	Completed a **3rd party employee engagement survey** and set a baselines for engagement and key diversity variables	Committed to **at least 30% of our directors being women** by our 2023 shareholder meeting

Not started In progress Completed

Supplementary Information

2023 Guidance and Cost Assumptions

Exploration and development expenditures ($ millions)	$575 - $650
Production (boe/d)	86,000 - 89,000
Expenses:	
Average royalty rate (%) (1)	20.0% - 22.0%
Operating ($/boe) (2)	$14.00 - $14.75
Transportation ($/boe) (2)	$1.90 - $2.10
General and administrative ($ millions) (2)	$52 ($1.63/boe)
Interest ($ millions) (2)	$65 ($2.04/boe)
Leasing expenditures ($ millions)	$4
Asset retirement obligations ($ millions)	$25

(1) Non-GAAP financial ratio that is not a standardized financial measure under IFRS and may not be comparable to similar measures disclosed by other issuers. See "Specified Financial Measures" in the Q3/2022 MD&A for information related to this non-GAAP financial measure, which information is incorporated by reference into this presentation.
(2) Information related to this supplementary financial measure is available in the Q3/2022 MD&A under the heading "Specified Financial Measures" and is incorporated by reference into this presentation.

Summary of Operating and Financial Metrics

	Q1 2021	Q2 2021	Q3 2021	Q4 2021	2021	Q1 2022	Q2 2022	Q3 2022
Benchmark Prices								
WTI crude oil (US$/bbl)	$57.84	$66.07	$70.56	$77.19	**$67.92**	$94.29	$108.41	$91.56
NYMEX natural gas (US$/mcf)	$2.69	$2.83	$4.01	$5.83	**$3.84**	$4.95	$7.17	$8.20
Production								
Crude oil (bbl/d)	57,419	58,403	57,610	58,468	**57,977**	59,301	61,593	62,491
Natural gas liquids (bbl/d)	6,238	7,563	7,174	7,984	**7,244**	7,636	7,468	7,536
Natural gas (mcf/d)	90,739	91,172	90,528	86,029	**89,606**	83,574	84,169	79,003
Oil equivalent (boe/d) (1)	**78,780**	**81,162**	**79,872**	**80,789**	**80,156**	**80,867**	**83,090**	**83,194**
% Liquids	**81%**	**81%**	**82%**	**82%**	**82%**	**82%**	**83%**	**84%**
Netback ($/boe)								
Total sales, net of blending and other expenses (2)	$51.84	$57.19	$63.85	$70.42	**$60.93**	$86.89	$105.44	$87.68
Royalties (3)	(9.44)	(11.04)	(12.32)	(13.47)	**(11.59)**	(16.86)	(22.69)	(19.21)
Operating expense (3)	(11.36)	(11.22)	(11.46)	(12.83)	**(11.72)**	(13.85)	(14.21)	(14.39)
Transportation expense (3)	(1.24)	(1.01)	(1.06)	(1.10)	**(1.10)**	(1.27)	(1.56)	(1.67)
Operating Netback (2)	$29.80	$33.92	$39.01	$43.02	**$36.52**	$54.91	$66.98	$52.41
General and administrative (3)	(1.23)	(1.44)	(1.36)	(1.54)	**(1.39)**	(1.61)	(1.54)	(1.57)
Cash financing and interest (3)	(3.44)	(3.19)	(3.10)	(2.87)	**(3.15)**	(2.81)	(2.71)	(2.58)
Realized financial derivative gain (loss) (3)	(2.93)	(5.28)	(7.34)	(9.49)	**(6.30)**	(11.59)	(16.41)	(9.98)
Other (4)	(0.12)	(0.20)	(0.21)	(0.23)	**(0.19)**	(0.48)	(0.60)	(1.14)
Adjusted funds flow (5)	**$22.08**	**$23.81**	**$27.00**	**$28.89**	**$25.49**	**$38.42**	**$45.72**	**$37.14**

(1) Barrel of oil equivalent ("boe") amounts have been calculated using a conversion rate of six thousand cubic feet of natural gas to one barrel of oil. The use of boe amounts may be misleading, particularly if used in isolation. A boe conversion ratio of six thousand cubic feet of natural gas to one barrel of oil is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

(2) Non-GAAP financial measure that is not a standardized financial measure under IFRS and may not be comparable to similar measures disclosed by other issuers. See "Specified Financial Measures" in the Q3/2022 MD&A for information related to this non-GAAP financial measure, which information is incorporated by reference into this presentation.

(3) Information related to this supplementary financial measure is available in the Q3/2022 MD&A under the heading "Specified Financial Measures" and is incorporated by reference into this presentation.

(4) Other is comprised of realized foreign exchange gain or loss, other income or expense, current income tax expense or recovery and share based compensation. Refer to the Q3/2022 MD&A for further information on these amounts.

(5) Information related to this capital management measure is available in the Q3/2022 MD&A under the heading "Specified Financial Measures" and is incorporated by reference into this presentation.

Forward Looking Statements Advisory

Any "financial outlook" or "future oriented financial information" in this presentation as defined by applicable securities laws, has been approved by management of Baytex. Such financial outlook or future oriented financial information is provided for the purpose of providing information about management's current expectations and plans relating to the future. Readers are cautioned that reliance on such information may not be appropriate for other circumstances.

In the interest of providing the shareholders of Baytex and potential investors with information regarding Baytex, including management's assessment of future plans and operations, certain statements in this presentation are "forward-looking statements" within the meaning of the United States Private Securities Litigation Reform Act of 1995 and "forward-looking information" within the meaning of applicable Canadian securities legislation (collectively, "forward-looking statements"). In some cases, forward-looking statements can be identified by terminology such as "anticipate", "believe", "continue", "could", "estimate", "expect", "forecast", "intend", "may", "objective", "ongoing", "outlook", "potential", "project", "plan", "should", "target", "would", "will" or similar words suggesting future outcomes, events or performance. The forward-looking statements contained in this presentation peak only as of the date hereof and are expressly qualified by this cautionary statement.

Specifically, this presentation contains forward-looking statements relating to but not limited to: that we have 10+ years of drilling inventory in core areas and strong capital efficiencies across the portfolio; we have >125 net prospective sections in the Clearwater, one of the most profitable plays; that our 5-year plan (2022-2026) generates ~$3.1 billion of free cash flow at $80 WTI and >50% of free cash flow over the five year period is to be returned to shareholders at US$80 WTI; that we will be allocating ~25% of our free cash flow to share buybacks, 50% of free cash flow to share buybacks when net debt reaches $800 million and 75% of free cash flow to direct shareholder returns when net debt reaches $400 million; our GHG emissions intensity reduction and end of life well inventory reduction targets; expectations for 2023 as to Baytex's production on a boe/d basis, percentage of production that will be liquids, exploration and development expenditures and our expected production by area and commodity; expected exit production rate of 87,000 to 88,000 boe/d for 2022; in 2022, that exploration and development expenditures represent ~45% of adjusted funds flow; our expected 2022 production and production per share growth rate; our 30% board gender diversity target; by operating area, the number of net wells onstream and capital expenditures in 2023; for 2023: our expected production and production per share growth rate, capital efficiency, that US$55 WTI fully funds our exploration and development program, our capital allocation between light and heavy oil and that we expect to generate ~$500 million of free cash flow; our expected net debt at year-end 2022 and 2023 at US$70/80/90/100 bbl WTI; our shareholder return framework at current and forecast net debt levels of $800 million and $400 million and our intent to increase our allocation of free cash flow to share buybacks and direct shareholder returns from 25% to 50% and then 75%, and the anticipated timing to reach the targeted net debt levels at US$70/80/90/100 bbl WTI; that we anticipate exiting 2022 with net debt of <$1 billion; our 2023 expectations for exploration and development spending, ARO expenditures, debt repayment, share buybacks and associated yield at US$70/80/90/100 bbl WTI; that at US$80/bbl WTI, our 5-year plan generates ~$3.1 billion of cumulative free cash flow, targets capital spending at ~50% of adjusted funds flow, generates 2-4% annual production growth and adjusted funds flow per share increases 50% (2022 to 2026); for each year of our 5-year plan: expected average daily production, adjusted funds flow, adjusted funds flow per share, capital expenditures, ARO / leasing expenditures and after-tax free cash flow; for our 5-year plan the forecasted cumulative free cash flow generated, free cash flow returned to shareholders, free cash flow allocated to debt repayment and net debt to Bank EBITDA at US$70/80/90/100 bbl WTI; the percentage of our expected production that is hedged for 2022 and 2023; the sensitivity of our expected 2023 adjusted funds flow to changes in WTI prices, WCS and MSW differentials, natural gas prices and the Canada-United States foreign exchange rate on a hedged and unhedged basis; that we have ~10 years of more drilling inventory in each core area; for the Eagle Ford that we expect to bring ~15 net wells on production in 2023; for the Viking that a stable production base drives meaningful asset level free cash flow, an expected netback of ~$66/boe at US$80 WTI, we expect to bring ~144 wells online in 2023, the asset has strong price realizations and a low cost structure and the approximate free cash flow it will generate at US$70/80/90bbl WTI in 2022; in Heavy Oil, that low decline production provides capital allocation flexibility, innovative multi-lateral horizontal drilling generates strong capital efficiencies, 10 net Bluesky multilateral wells are planned for 2023 and 33 Clearwater wells are planned for 2023 (31 at Peavine and 2 at Seal); for the Northwest Clearwater that we have >125 sections prospective for Sprit River (Clearwater equivalent), we will drill a follow-up Clearwater well on our legacy Seal lands in Q4/2022, that we have de-risked 50 sections, the potential for a 20% increase in future Peavine Clearwater inventory due to down spacing and we believe the play holds the potential for >250 locations; we expect to bring ~40 net wells on production in 2023 in Lloydminster and pursue a long-life polymer flood and water flood projects at Soda Lake and Tangleflags; in Pembina Area Duvernay, we have delineated a minimum of 100-125 sections, continue to advance the delineation and plan to bring 6 wells on production in 2023; the expected individual well payout, IRR and recycle ratio for wells in the Eagle Ford, Viking, Peace River, Clearwater and Lloydminster areas; the expected drill, complete, equip and tie-in well costs, reserves and drilling inventory for our Eagle Ford, Peace River, Clearwater, Lloydminster, Viking and Pembina Duvernay assets; our values, visions and approach to ESG; that we are committed to corporate sustainability; the components of our GHG emissions reduction strategy; our new ESG targets: reducing our GHG emissions intensity by 65% by 2025 from our 2018 baseline, reducing our 2020 end of life well inventory of 4,500 wells to zero by 2040 and spending $100 million from 2022 to 2026 on abandonment and reclamation, developing an internal management framework that prioritizes reduced freshwater use, and having 30% women directors by our 2023 shareholder meeting; and our 2023 guidance for exploration and development expenditures, production, royalty rate, operating, transportation, general and administration and interest expense and leasing expenditures and asset retirement obligations. In addition, information and statements relating to reserves are deemed to be forward-looking statements, as they involve implied assessment, based on certain estimates and assumptions, that the reserves described exist in quantities predicted or estimated, and that they can be profitably produced in the future.

Forward Looking Statements Advisory (Cont.)

These forward-looking statements are based on certain key assumptions regarding, among other things: petroleum and natural gas prices and differentials between light, medium and heavy oil prices; well production rates and reserve volumes; the ability to add production and reserves through exploration and development activities; capital expenditure levels; the ability to borrow under credit agreements; the receipt, in a timely manner, of regulatory and other required approvals for operating activities; the availability and cost of labour and other industry services; interest and foreign exchange rates; the continuance of existing and, in certain circumstances, proposed tax and royalty regimes; the ability to develop crude oil and natural gas properties in the manner currently contemplated; and current industry conditions, laws and regulations continuing in effect (or, where changes are proposed, such changes being adopted as anticipated). Readers are cautioned that such assumptions, although considered reasonable by Baytex at the time of preparation, may prove to be incorrect.

Actual results achieved will vary from the information provided herein as a result of numerous known and unknown risks and uncertainties and other factors. Such factors include, but are not limited to: the volatility of oil and natural gas prices and price differentials (including the impacts of Covid-19); restrictions or costs imposed by climate change initiatives and the physical risks of climate change; risks associated with our ability to develop our properties and add reserves; the impact of an energy transition on demand for petroleum productions; changes in income tax or other laws or government incentive programs; availability and cost of gathering, processing and pipeline systems; retaining or replacing our leadership and key personnel; the availability and cost of capital or borrowing; risks associated with a third-party operating our Eagle Ford properties; risks associated with large projects; costs to develop and operate our properties; public perception and its influence on the regulatory regime; current or future control, legislation or regulations; new regulations on hydraulic fracturing; restrictions on or access to water or other fluids; regulations regarding the disposal of fluids; risks associated with our hedging activities; variations in interest rates and foreign exchange rates; uncertainties associated with estimating oil and natural gas reserves; our inability to fully insure against all risks; additional risks associated with our thermal heavy oil projects; our ability to compete with other organizations in the oil and gas industry; risks associated with our use of information technology systems; results of litigation; that our credit facilities may not provide sufficient liquidity or may not be renewed; failure to comply with the covenants in our debt agreements; risks of counterparty default; the impact of Indigenous claims; risks associated with expansion into new activities; risks associated with the ownership of our securities, including changes in market-based factors; risks for United States and other non-resident shareholders, including the ability to enforce civil remedies, differing practices for reporting reserves and production, additional taxation applicable to non-residents and foreign exchange risk; and other factors, many of which are beyond our control. These and additional risk factors are discussed in our Annual Information Form, Annual Report on Form 40-F and Management's Discussion and Analysis for year ended December 31, 2021, filed with Canadian securities regulatory authorities and the U.S. Securities and Exchange Commission and in our other public filings.

The above summary of assumptions and risks related to forward-looking statements has been provided in order to provide shareholders and potential investors with a more complete perspective on Baytex's current and future operations and such information may not be appropriate for other purposes.

Specified Financial Measures Advisory

In this presentation, we refer to certain specified financial measures (such as free cash flow, operating netback, total sales, net of blending and other expense, heavy oil sales, net of blending and other expense, and average royalty rate) which do not have any standardized meaning prescribed by International Financial Reporting Standards ("IFRS"). While these measures are commonly used in the oil and natural gas industry, our determination of these measures may not be comparable with calculations of similar measures presented by other reporting issuers.

Refer to "Specified Financial Measures" in the Q3/2022 MD&A for additional information on the following specified financial measures, which information is incorporated by reference into this presentation.

Non-GAAP Financial Measures

Total sales, net of blending and other expense

Total sales, net of blending and other expense represents the revenues realized from produced volumes during a period. Total sales, net of blending and other expense is comprised of total petroleum and natural gas sales adjusted for blending and other expense. We believe including the blending and other expense associated with purchased volumes is useful when analyzing our realized pricing for produced volumes against benchmark commodity prices.

Operating netback

Operating netback and operating netback after financial derivatives are used to assess our operating performance and our ability to generate cash margin on a unit of production basis. Operating netback is comprised of petroleum and natural gas sales, less blending expense, royalties, operating expense and transportation expense. Realized financial derivatives gains and losses are added to operating netback to provide a more complete picture of our financial performance as our financial derivatives are used to provide price certainty on a portion of our production.

Free cash flow

We use free cash flow to evaluate our financial performance and to assess the cash available for debt repayment, common share repurchases, dividends and acquisition opportunities. Free cash flow is comprised of cash flows from operating activities adjusted for changes in non-cash working capital, additions to exploration and evaluation assets, additions to oil and gas properties and payments on lease obligations.

Non-GAAP Financial Ratios

Total sales, net of blending and other expense per boe

Total sales, net of blending and other per boe is used to compare our realized pricing to applicable benchmark prices and is calculated as total sales, net of blending and other expense (a non-GAAP financial measure) divided by barrels of oil equivalent production volume for the applicable period.

Average royalty rate

Average royalty rate is used to evaluate the performance of our operations from period to period and is comprised of royalties divided by total sales, net of blending and other expense (a non-GAAP financial measure). The actual royalty rates can vary for a number of reasons, including the commodity produced, royalty contract terms, commodity price level, royalty incentives and the area or jurisdiction.

Operating netback per boe

Operating netback per boe is operating netback (a non-GAAP financial measure) divided by barrels of oil equivalent production volume for the applicable period and is used to assess our operating performance on a unit of production basis. Realized financial derivative gains and losses per boe are added to operating netback per boe to arrive at operating netback after financial derivatives per boe. Realized financial derivatives gains and losses are added to operating netback to provide a more complete picture of our financial performance as our financial derivatives are used to provide price certainty on a portion of our production.

Capital Management Measures Advisory

This presentation contains the terms "adjusted funds flow", "net debt", "net debt to adjusted funds flow ratio" and "net debt to EBITDA" which are capital management measures. We believe that inclusion of these specified financial measures provides useful information to financial statement users when evaluating the financial results of Baytex.

Net debt

We use net debt to monitor our current financial position and to evaluate existing sources of liquidity. We also use net debt projections to estimate future liquidity and whether additional sources of capital are required to fund ongoing operations. Net debt is comprised our credit facilities and long-term notes outstanding adjusted for unamortized debt issuance costs, trade and other payables, cash, and trade and other receivables. We also use a net debt to Bank EBITDA ratio to evaluate the amount of debt we have in our capital structure on an ongoing basis. Net debt to EBITDA ratio is comprised of net debt divided by Bank EBITDA. Bank EBITDA is calculated in accordance with our credit facility which is accessible on the SEDAR website at www.sedar.com.

Adjusted funds flow

Adjusted funds flow is used to monitor operating performance and the our ability to generate funds for exploration and development expenditures and settlement of abandonment obligations. Adjusted funds flow is comprised of cash flows from operating activities adjusted for changes in non-cash working capital and asset retirements obligations settled during the applicable period. We also use a net debt to adjusted funds flow ratio calculated on a twelve-month trailing basis to monitor our existing capital structure and future liquidity requirements. Net debt to adjusted funds flow is comprised of net debt divided by adjusted funds flow.

Advisory Regarding Oil and Gas Information

The reserves information contained in this presentation has been prepared in accordance with National Instrument 51-101 -Standards of Disclosure for Oil and Gas Activities of the Canadian Securities Administrators ("NI 51-101"). The determination of oil and gas reserves involves the preparation of estimates that have an inherent degree of associated uncertainty. Categories of proved and probable reserves have been established to reflect the level of these uncertainties and to provide an indication of the probability of recovery. The estimation and classification of reserves requires the application of professional judgment combined with geological and engineering knowledge to assess whether or not specific reserves classification criteria have been satisfied. Knowledge of concepts, including uncertainty and risk, probability and statistics, and deterministic and probabilistic estimation methods, is required to properly use and apply reserves definitions.

The recovery and reserves estimates described herein are estimates only and there is no guarantee that the estimated reserves will be recovered. Actual reserves and future production from such reserves may be greater or less than the estimates provided herein. The estimates of reserves for individual properties may not reflect the same confidence level as estimates of reserves for all properties, due to the effects of aggregation. Complete NI 51-101 reserves disclosure for year-end 2021 is included in our Annual Information Form for the year ended December 31, 2021 which will be filed with Canadian securities regulatory authorities and the U.S. Securities and Exchange Commission no later than March 31, 2022.

This presentation discloses drilling inventory and potential drilling locations. Drilling inventory and drilling locations refers to Baytex's total proved, probable and unbooked locations. Proved locations and probable locations account for drilling locations in our inventory that have associated proved and/or probable reserves. Unbooked locations are internal estimates based on our prospective acreage and an assumption as to the number of wells that can be drilled per section based on industry practice and internal review. Unbooked locations do not have attributed reserves. Unbooked locations are farther away from existing wells and, therefore, there is more uncertainty whether wells will be drilled in such locations and if drilled there is more uncertainty whether such wells will result in additional oil and gas reserves, resources or production. In the Eagle Ford, Baytex's net drilling locations include 129 proved and 58 probable locations as at December 31, 2021 and 37 unbooked locations. In the Viking, Baytex's net drilling locations include 936 proved and 222 probable locations as at December 31, 2021 and 490 unbooked locations. In Peace River (including Clearwater), Baytex's net drilling locations include 61 proved and 37 probable locations as at December 31, 2021 and 334 unbooked locations. In Lloydminster, Baytex's net drilling locations include 82 proved and 63 probable locations as at December 31, 2021 and 423 unbooked locations. In the Duvernay, Baytex's net drilling locations include 17 proved and 12 probable locations as at December 31, 2021 and 231 unbooked locations.

References herein to average 30-day initial production rates and other short-term production rates are useful in confirming the presence of hydrocarbons, however, such rates are not determinative of the rates at which such wells will commence production and decline thereafter and are not indicative of long term performance or of ultimate recovery. While encouraging, readers are cautioned not to place reliance on such rates in calculating aggregate production for us or the assets for which such rates are provided. A pressure transient analysis or well-test interpretation has not been carried out in respect of all wells. Accordingly, we caution that the test results should be considered to be preliminary.

Where applicable, oil equivalent amounts have been calculated using a conversion rate of six thousand cubic feet of natural gas to one barrel of oil. BOEs may be misleading, particularly if used in isolation. A boe conversion ratio of six thousand cubic feet of natural gas to one barrel of oil is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

Notice to United States Readers

The petroleum and natural gas reserves contained in this presentation have generally been prepared in accordance with Canadian disclosure standards, which are not comparable in all respects to United States or other foreign disclosure standards. For example, the United States Securities and Exchange Commission (the "SEC") requires oil and gas issuers, in their filings with the SEC, to disclose only "proved reserves", but permits the optional disclosure of "probable reserves" (as defined in SEC rules). Canadian securities laws require oil and gas issuers disclose their reserves in accordance with NI 51-101, which requires disclosure of not only "proved reserves" but also "probable reserves". Additionally, NI 51-101 defines "proved reserves“ and "probable reserves" differently from the SEC rules. Accordingly, proved and probable reserves disclosed in this presentation may not be comparable to United States standards. Probable reserves are higher risk and are generally believed to be less likely to be accurately estimated or recovered than proved reserves.

In addition, under Canadian disclosure requirements and industry practice, reserves and production are reported using gross volumes, which are volumes prior to deduction of royalty and similar payments. The SEC rules require reserves and production to be presented using net volumes, after deduction of applicable royalties and similar payments.

Moreover, in this presentation future net revenue from its reserves has been determined and disclosed estimated using forecast prices and costs, whereas the SEC rules require that reserves be estimated using a 12-month average price, calculated as the arithmetic average of the first-day-of-the-month price for each month within the 12-month period prior to the end of the reporting period. As a consequence of the foregoing, the reserve estimates and production volumes in this presentation may not be comparable to those made by companies utilizing United States reporting and disclosure standards.

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